COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

AN ELECTRONIC EXAMINATION OF THE APPLICATION OF THE FUEL ADJUSTMENT CLAUSE OF KENTUCKY POWER COMPANY FROM NOVEMBER 1, 2020 THROUGH OCTOBER 31, 2022	: : :	**Case No 2023-00008**

JOINT BRIEF OF ATTORNEY GENERAL AND KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.

The Attorney General ("AG") and Kentucky Industrial Utility Customers, Inc. ("KIUC") submit this Joint Brief in support of their recommendations to the Kentucky Public Service Commission ("Commission").

INTRODUCTION

During the two-year review period, Kentucky Power Company's ("Kentucky Power" or "Company") application of its peaking unit equivalent ("PUE") methodology resulted in unfair, unjust, and unreasonable Fuel Adjustment Clause ("FAC") charges to its retail customers. The Company's assumptions that the hypothetical combustion turbine ("CT") used in its PUE calculation would start and stop all 8,760 hours of the year and could grow to unlimited size is unrealistic and resulted in an inflated PUE cap. An inflated PUE cap made Kentucky Power's high-cost purchases appear to be economic when they were not.

The Company asserts that 98.1% of its $238.7 million energy purchases were "*economy*" and therefore fully recoverable in the FAC. Despite having more than twice the generating capacity (1,430 MW) of its average customer load (654 MW), the Company purchased 44% of its energy requirements instead of relying on its own lower-cost generation. The Company purchased 5,003,180 MWh at an average price of $47.71/MWh ($238.7 million total) compared to the fuel cost of its own generation: $23/MWh at Mitchell 1, $23/MWh at Mitchell 2, $37/MWh at Rockport 1, $34/MWh at Rockport 2, and $53/MWh at Big Sandy. The annual fixed cost to

customers of these power plants in base rates, the environmental surcharge, and Tariff PPA is approximately $173 million. But these expensive base load power plants failed to perform, and an inflated PUE shifted almost all market risk to customers.

The Commission should require Kentucky Power to use reasonable assumptions when applying the PUE, including startup and sizing assumptions that mimic the operations of an actual peaking plant. Kentucky Power's unrealistic PUE calculation resulted in a disallowance of only $4.52 million over the two-year review period. However, applying a realistic startup cost assumption without changing the Company's unlimited CT sizing assumption produces a total disallowance of $14.76 million – $10.24 million more than the Company's calculated disallowance. Applying both a realistic startup cost assumption and a 100 MW CT size cap produces a total PUE disallowance of $59.79 million – or $55.27 million more than the Company's calculated disallowance. And applying both a realistic startup cost assumption and a 200 MW CT size cap produces a total PUE disallowance of $44.35 million – or $39.83 million more than the Company's calculated disallowance.

Refunding unreasonable FAC charges is consistent with long-standing Commission precedent and the directives of 807 KAR 5:056. Indeed, the Commission ordered a refund of unreasonable FAC charges collected by Kentucky Power as recently as 2015. Finding that Kentucky Power had unreasonably allocated $54 million in *"no load"* fuel costs to native load customers, the Commission required the Company to refund the entire amount.[1] The Commission has ordered refunds of unlawful FAC charges recovered by other Kentucky utilities as well.[2]

[1] Order, Case No. 2014-00225 (January 22, 2015).
[2] Order, Case Nos. 94-461-A *et al.* (August 30, 1999); Order, Case Nos. 96-524-A *et al* (December 2, 1999); Order, Case No. 2014-00226 (July 10, 2015); Order, Case No. 90-360C-C (July 21, 1994).

Moreover, requiring that Kentucky Power use reasonable assumptions in its PUE calculation will incentivize it to maintain and to rely upon its existing generating units to serve native load customers rather than depending upon high-cost, high-risk short-term market energy purchases. Kentucky Power's request to make almost all of its PJM energy purchases automatically recoverable through the FAC not only provides the opposite incentive but is contrary to the customer protections grounded in 807 KAR 5:056 and the Commission's prior orders.

LEGAL STANDARD

The Commission regulation governing Kentucky electric utility FACs – 807 KAR 5:056 – was promulgated pursuant to KRS 278.030(1), which requires rates to be *"fair, just and reasonable,"* and KRS 278.030(2), which requires utilities to furnish *"adequate, efficient and reasonable service."* 807 KAR 5:056 details the types of costs that are recoverable under an FAC as well as the process by which the Commission determines their recoverability.

Costs recoverable through an FAC pursuant to 807 KAR 5:056 include the costs of fossil fuel consumed in the utility's own plants or in plants jointly owned or leased, costs of replacement energy due to forced outages at the utility's plants subject to a cap, and costs resulting from "*economy*" energy purchases. The Commission defines *"economy"* energy purchases as *"purchases that an electric utility makes to serve native load, that displace its higher cost of generation, and that have an energy cost less than the avoidable variable generation cost of the utility's highest cost generating unit available to serve native load during that FAC expense month."*[3] In contrast, *"non-economy"* energy purchases are defined as *"purchases made to serve native load that have an energy cost greater than the avoided variable cost of the utility's highest cost generating unit available to service native load during*

[3] Order, Case No. 2022-00402 (November 6, 2023).

that FAC expense month."[4] *"Non-economy"* energy purchases are not fully recoverable through the FAC but are eligible for recovery in base rates.[5]

With respect to the review process, 807 KAR 5:056 requires the Commission to conduct six-month reviews of electric utility FACs and to order refunds of any charges that the Commission finds *"unjustified due to improper calculation or application of the charge or improper fuel procurement practices."* The Commission is also required to conduct two-year reviews of electric utility FACs in which the Commission *"evaluate[s] past operations of the clause"* and disallows *"improper expenses."* Under 807 KAR 5:056, *"fuel charges that are unreasonable shall be disallowed and may result in the suspension of the fuel adjustment clause based on the severity of the utility's unreasonable fuel charges and any history of unreasonable fuel charges."*

BACKGROUND OF KENTUCKY POWER'S FAC METHODOLOGY

For most Kentucky electric utilities, the threshold between *"economy"* and *"non-economy"* energy purchases is measured by their highest fuel cost generating unit. However, in 2002, because Kentucky Power was unique in that it did not own a high fuel cost CT peaking plant, the Commission approved Kentucky Power's use of the hypothetical PUE ratemaking methodology to determine whether its energy purchases are economic and therefore fully recoverable through its FAC.[6]

As initially approved, the PUE methodology was based upon the operating characteristics of a General Electric simple cycle gas turbine.[7] The cost of gas used in the calculation was the sum of the daily midpoint price for Columbia Gas Transmission (delivered Citygate) as published

[4] Order, Case No. 2022-00402 (November 6, 2023).
[5] Order, Case No. 2022-00190 (November 2, 2022).
[6] Order, Case No. 2000-00495-B (October 3, 2002).
[7] Id.

in that day's edition of *Platt's Gas Daily* and the current tariff rate for Columbia's Park and Lend Rate. When a power purchase occurred during an expense month, Kentucky Power would determine whether the actual average purchased energy cost for internal use for the month was greater than 75% of the lowest daily market price for gas for the hypothetical CT. If so, Kentucky Power would exclude from the FAC any of the actual purchased energy costs that exceeded the daily gas market price.[8]

Kentucky Power adhered to the approved PUE methodology from 2002 until 2005, but unilaterally disregarded that methodology for nearly ten years based upon a misinterpretation of an East Kentucky Power Cooperative FAC order issued by the Commission on March 21, 2005 in Case No. 2004-00430.[9] Kentucky Power's error was not corrected until a two-year FAC review completed by the Commission in 2015.

In the same 2015 two-year review, the Commission held that Kentucky Power's FAC methodology was unreasonable as applied because the Company had unfairly allocated 100% of the *"no load"* fuel costs for all six of its generating units to native load customers each hour even when those units were not necessary to serve native load.[10] Kentucky Power argued that its allocation practice had been in place for at least thirty years and that any change to its methodology could only be made prospectively when base rates were modified.[11] The Commission disagreed, finding that because Kentucky Power failed to disclose the impact of its *"no load"* fuel cost allocation methodology in the Mitchell transfer case (Case No. 2012-00578) and because the application of Kentucky Power's methodology produced an unreasonable result, 100% of the *"no load"* fuel costs ($54 million) should be disallowed.[12] AEP promoted the Mitchell purchase to the Commission in part by arguing that it would reduce fuel costs. But the

[8] Order, Case No. 2000-00495-B (October 3, 2002).
[9] Order, Case No. 2014-00225 (January 22, 2015) at 3-4.
[10] Order, Case No. 2014-00225 (January 22, 2015).
[11] Id.
[12] Order, Case No. 2014-00225 (January 22, 2015) at 10-11.

opposite occurred. The $54 million FAC disallowance was necessary to give customers the deal that they were promised.

Two years later, Kentucky Power sought to include three new cost categories in the PUE calculation: 1) startup costs; 2) variable O&M; and 3) firm gas service.[13] In support of its proposals, Company witness Vaughan explained that *"[t]he peaking unit equivalent cost calculation seeks to mimic the costs of operating an actual CT because the Company does not own a real CT for the purposes of calculating the FAC Purchased Power Limitation."*[14] Regarding startup costs, witness Vaughan testified that the expenses to be included *"are real costs that the hypothetical CT would incur in order to generate electricity and should be included in the peaking unit equivalent cost calculation."*[15] In his exhibit quantifying the startup costs to be included in the modified PUE calculation, witness Vaughan listed startup costs of $30.00/MWh for each month.[16] That $30.00/MWh quantification was derived based upon the actual operations of its affiliate's 100 MW Ceredo 1 CT.[17]

The Commission ultimately approved the inclusion of startup costs and variable O&M costs in the PUE calculation but rejected the proposal to include firm gas service.[18] In doing so, the Commission explained it was *"unaware of any jurisdictional utility utilizing firm gas service for a CT. Because CTs typically operate at low capacity factors and are primarily utilized during the summer peaking months, when pipeline capacity would not be constrained, the Commission finds the inclusion of firm gas service in the calculation of the PUE to be unreasonable…"*[19]

---

[13] Order, Case No. 2017-00179 (January 18, 2018) at 55-56.
[14] Vaughan Testimony, Case No. 2017-00179 at 34:4-7.
[15] Id. at 34:8-12.
[16] Direct Testimony of Randy Futral at 10:14-20; Company Ex. 1.
[17] Company's Response to Staff's Post-Hearing Data Request 2, Attachment 1 in Case No. 2022-00036. The $30/MWh startup cost is based on hypothetical startup costs of $3,000 for a hypothetical 100 MW unit.
[18] Order, Case No. 2017-00179 (January 18, 2018).
[19] Order, Case No. 2017-00179 (January 18, 2018) at 55-56.

ARGUMENT

I. The PUE Methodology Should Be Applied In A Manner That Results In Just and Reasonable Rates For Kentucky Power's Customers.

As the long-standing history of the PUE methodology reflects, the objective of allowing Kentucky Power to use a hypothetical peaking unit to determine the *"economy"* energy purchase threshold was to put the Company on equal footing with other electric utilities in Kentucky. While Kentucky Power did not own a high fuel cost CT peaking plant, the PUE was established with the aim of *"mimicking"* the operations of a real CT as much as possible.[20] Kentucky Power acknowledged this objective as recently as 2017, explaining *"[t]he peaking unit equivalent cost calculation seeks to mimic the costs of operating an actual CT because the Company does not own a real CT for the purposes of calculating the FAC Purchased Power Limitation."*[21] And the principle reason for the Commission's denial of the Company's proposal to include firm gas service in the PUE calculation was that such a change did not reflect the operations of an actual CT. [22]

Kentucky Power's application of the PUE during the two-year review period is at odds with this objective. As discussed below, its startup cost and CT size assumptions do not *"mimic"* the operations of an actual CT. Rather, those assumptions artificially inflate the PUE cap, undermining the objective of keeping Kentucky Power on equal footing with the other Kentucky electric utilities. While Kentucky Power is incentivized to adopt PUE assumptions that increase its cap, thereby rendering more market purchases *"economy"* purchases recoverable through its FAC, an unreasonably inflated PUE cap is inconsistent with Commission precedent and 807 KAR 5:056.

[20] Order, Case No. 2000-00495-B (October 3, 2002).
[21] Vaughan Testimony, Case No. 2017-00179 at 34:4-7.
[22] Order, Case No. 2017-00179 (January 18, 2018) at 55-56.

A. Kentucky Power's Startup Cost Assumptions Were Unreasonable.

During the two-year review period, the Company calculated its PUE cap as follows: 1) Kentucky Power determined the cost of gas that would have been burned by a hypothetical gas-fired CT in a single hour by multiplying the daily market price for natural gas by a heat rate of 10,400 Btu/kWh for nine months out of the year and 10,800 Btu/kWh during the summer months of June through August; 2) it added hypothetical startup costs of $30.00/MWh each of the 8,670 hours of the year; and 3) it added variable O&M costs of $3.48/MWh.[23] For example, the following calculation was performed by the Company to determine the PUE for the first hour on November 1, 2021, based on a daily market price of gas that day of $5.05/MMbtu:

Gas Costs ($5.05/MMbtu x (10,400/1,000)) Btu/MWh	$52.50/MWh
Fixed Startup Costs	$30.00/MWh
Variable O&M Costs	$3.48/MWh
PUE Cap – November 1, 2021 Hour 1	$86.00/MWh

While Kentucky Power's gas pricing and variable O&M assumptions over the review period were reasonable, its assumption that the hypothetical CT would start and stop every hour of the entire year was improper and produced an artificially inflated PUE cap. In the real-world, no CT would or could start and stop every hour of the year.[24] The Company's PUE calculation during the two years at issue therefore did not reflect the *"real costs"* of operating a CT.[25]

Nor did Kentucky Power disclose this unreasonable assumption to the Commission when it initially sought approval to include startup costs in the PUE calculation in 2017. Supporting detail regarding how the $30.00/MWh startup cost was derived was not provided by the Company until Kentucky Power produced discovery responses in Case No. 2022-00036.[26] In

[23] Futral Testimony at 5:14-6:12.
[24] Id. at 9:2-8.
[25] Id. at 8:7-12; Vaughan Testimony, Case No. 2017-00179 at 34.
[26] Company's Response to Staff's Post-Hearing Data Request 2, Attachment 1 in Case No. 2022-00036. The $30/MWh startup cost is based on hypothetical startup costs of $3,000 for a hypothetical 100 MW unit.

those responses, Kentucky Power revealed that Appalachian Power's 100 MW Ceredo 1 was the real-world unit relied upon as the model for the hypothetical PUE. Startup costs for Ceredo 1 were assumed to be $3,000 per start, which included "*start up fuel consumed, station power requirements and start up maintenance and labor.*"[27] Because the Company assumed 8,760 starts and stops per year, its math was $3,000/100 MW = $30/MWh.[28]

Kentucky Power's calculations do not reflect reality. Ceredo 1 CT incurs $3,000 in startup costs *only* in the hour that it is started. For example, if Ceredo 1 runs for 14 hours, its startup costs over the entire 14-hour runtime are $2.14/MWh ($3,000/100 MW/14 = $2.14/MWh). Kentucky Power confirmed that the Ceredo 1 *"[s]tartup costs are incurred on a per-start basis."*[29] And Kentucky Power conceded that in PJM, the startup costs of its generating units *"are calculated and submitted on a per-start basis in accordance with PJM protocols and are not calculated on a dollar-per-MWh basis."*[30] Accordingly, rather than assuming that its hypothetical CT would start and stop 8,760 times per year, Kentucky Power should have based its startup assumption on the real-world operations of Ceredo 1.

In 2021, the average runtime for the Ceredo 1 generating unit was 6.49 hours over 140 total starts.[31] The one-time $3,000 startup costs for Ceredo 1 averaged over the 6.49 hours of generation for each 2021 startup is equivalent to $4.62/MWh. Incorporating the real-world Ceredo 1 startup cost of $4.62/MWh into the PUE calculation over the two-year review period results in an additional PUE disallowance of $10,241,619. That disallowance is reflected in the following chart, which compares Kentucky Power's calculated PUE disallowance over the review

[27] Futral Testimony at 8; Vaughan Testimony, Case No. 2017-00179 at 34.
[28] Futral Testimony at 9:14-20.
[29] Futral Testimony, Ex. RAF-2 (Response to AG-KIUC 1-5 in Case No. 2022-00263).
[30] Futral Testimony, Ex. RAF-3 (Response to AG-KIUC 1-3(e) in Case No. 2022-00263).
[31] Generation by hour results for Ceredo Unit 1 were derived from SNL Financial S&P Capital Global Market Intelligence databases through its subscription service. The data obtained also references the original source of the data as the EPA's Continuous Emissions Monitoring System (CEMS).

period ($4,518,435) with a PUE disallowance incorporating realistic startup cost assumptions ($14,760,054).[32]

KPCo - PUE Disallowances
AG and KIUC Recommended PUE Disallowances
To Adjust for Changes in the Start-Up Costs
For The Twenty-Four Months November 2020 through October 2022
Case No. 2023-00008
$

Month	PUE Disallowance with $30/mWh Startup Costs for All Purchases	PUE Disallowance with $4.62/mWh Startup Costs for All Purchases	Variance
Nov 20	18,169	47,456	29,287
Dec 20	5,193	157,293	152,100
Jan 21	-	-	-
Feb 21	6,171	18,149	11,978
Mar 21	36,239	36,239	-
Apr 21	2,924	97,866	94,942
May 21	27,541	54,892	27,351
Jun 21	-	25,449	25,449
Jul 21	1,355	17,603	16,248
Aug 21	322,570	238,244	(84,326)
Sep 21	32,806	93,936	61,130
Oct 21	29,766	689,413	659,647
Nov 21	443,748	2,173,348	1,729,600
Dec 21	79,578	494,012	414,434
Jan 22	665,115	1,297,878	632,763
Feb 22	51,226	198,348	147,122
Mar 22	-	-	-
Apr 22	45,216	275,207	229,991
May 22	254,887	702,567	447,680
Jun 22	205,221	712,789	507,568
Jul 22	381,205	743,887	362,682
Aug 22	745,497	1,796,381	1,050,884
Sep 22	904,634	2,765,893	1,861,259
Oct 22	259,374	2,123,204	1,863,830
Total	4,518,435	14,760,054	10,241,619

[32] Futral Testimony at 13:4-15:2.

B. Kentucky Power's CT Size Assumptions Were Unreasonable.

The second unrealistic assumption that Kentucky Power applied in its PUE calculation relates to the maximum size of the hypothetical CT. Despite having based the startup costs and variable O&M within that calculation on its affiliate's 100 MW Ceredo 1 unit, Kentucky Power assumed that its hypothetical CT can be scaled up to any size to meet any capacity deficiency in any hour.[33]

To determine the PUE cap, Kentucky Power assumed that the internal load served through purchases in each hour (except for lost energy due to forced outages) was subject to the PUE.[34] For example, in hour 8 of December 1, 2021, Kentucky Power purchased 839 MW, the entirety of its native load. It had no generation from its own generating units in that hour. The Company had 395 MW of its generation on forced outage in that hour, so the remaining 444 MW of non-forced outage purchases were subject to the PUE. In hour 10 of February 19, 2022, Kentucky Power purchased 431 MW to meet its internal load of 907 MW. The Company had no forced outages in that hour, so the entire 431 MW of non-forced outage purchases was subject to the PUE.[35] In hour 20 of October 10, 2022, when Kentucky Power had no native generation available, all 611 MW of internal load was subject to the PUE.[36]

As these examples reflect, the size of the hypothetical CT used in Kentucky Power's PUE calculation increased well beyond the 100 MW Ceredo 1 unit used as the model for PUE methodology since 2017. This unlimited sizing assumption was unrealistic and artificially inflated the PUE cap to the harm of Kentucky Power's customers. The hypothetical CT used in the PUE calculation should align with the size of an actual CT.

---

[33] Kollen Testimony at 16:22-7.
[34] Id. at 17:8-11.
[35] Id. at 17:12-18:7.
[36] KIUC Ex. 3.

To accomplish this goal, the first option is to require Kentucky Power to use the 100 MW size of Ceredo 1 unit as the size of its hypothetical CT for purposes of the PUE calculation. This approach is reasonable because Ceredo 1 formed the basis for the PUE calculation since 2017. Alternatively, Commission Staff posited a second option in discovery: using two 100 MW natural gas-fired CTs.[37] Either hypothetical CT sizing cap is reasonable.

Once the hypothetical CT sizing cap is reached, the *"economy"* cap for any incremental energy purchases should be based on Kentucky Power's highest cost baseload coal-fired generating unit, consistent the economic dispatch principles reflected in 807 KAR 5:056. During the review period, the Company's highest fuel cost unit was typically Rockport Unit 1 at about $37/MWh. 807 KAR 5:056 allows the utility to include the cost of purchases *"if the energy is purchased on an economic dispatch basis"* and to include *"other charges for energy being purchased by the buyer to substitute for the buyer's own higher cost energy."* The economic principle is that the utility achieves the lowest cost fuel and purchased power expense when it dispatches from lowest cost generation to highest cost generation and when it purchases energy in order to avoid dispatching higher cost generation.

If the cost of a purchase exceeds the cost of the Company's highest cost baseload coal plant, then it should be treated as *"non-economy."* This is how the system would work in practice if the coal plants were reasonably operated, maintained, and dispatched. This change not only aligns the PUE methodology with real-world operations but also gives customers the fuel cost benefit of the high capital cost baseload power plants they are paying for.[38] Customers pay $173 million annually for the fixed capital costs of utility-owned generation.

[37] Kollen Testimony, Ex. LK-4 (Response to Staff Request to AG-KIUC 1-1 in Case No. 2022-00263).
[38] Kollen Testimony at 18:16-19:4.

The combined impact of requiring Kentucky Power to apply reasonable startup cost and hypothetical CT sizing assumptions over the two-year review period is a disallowance of between $39.8 million and $55.27 million, incorporating the 200 MW and 100 MW CT sizing assumptions, respectively.[39] Using a 100 MW CT size cap in the PUE calculation results in a combined disallowance of $59,785,373, which is $55,266,938 higher than the PUE disallowances calculated by the Company. This quantification is detailed in the following chart.

Kentucky Power Company
AG and KIUC Recommended PUE Disallowances
Based on 100mW Threshold
For The Twenty-Four Months November 2020 through October 2022
Case No. 2023-00008
$

Month	As Filed PUE Disallowance with $30/mWh Start-Up for All Purchases	PUE Disallowance with $4.62 mWh Start-Up for first 100 mW Purchases Each Hour	Additional PUE Disallowance for All Purchases Above 100 mW	Combined Modified PUE Disallowances	Increase in Disallowance As Filed PUE Disallowance vs Combined Modified PUE Disallowance
Nov 20	18,169	25,425	22,192	47,617	29,448
Dec 20	5,193	54,950	144,187	199,137	193,944
Jan 21	-	-	-	-	-
Feb 21	6,171	14,795	165,968	180,763	174,592
Mar 21	36,239	11,297	24,942	36,239	-
Apr 21	2,924	56,044	62,277	118,321	115,397
May 21	27,541	46,710	21,155	67,865	40,324
Jun 21	-	9,321	69,136	78,457	78,457
Jul 21	1,355	14,630	12,144	26,774	25,419
Aug 21	322,570	182,645	124,297	306,942	(15,628)
Sep 21	32,806	60,880	191,830	252,710	219,904
Oct 21	29,766	206,101	4,199,633	4,405,734	4,375,968
Nov 21	443,748	394,027	10,277,190	10,671,217	10,227,469
Dec 21	79,578	152,641	1,044,134	1,196,775	1,117,197
Jan 22	665,115	693,868	1,040,628	1,734,496	1,069,381
Feb 22	51,226	56,475	3,175,697	3,232,172	3,180,946
Mar 22	-	58,777	4,207,937	4,266,714	4,266,714
Apr 22	45,216	97,320	1,781,345	1,878,665	1,833,449
May 22	254,887	386,303	3,595,595	3,981,898	3,727,011
Jun 22	205,221	285,140	3,480,812	3,765,952	3,560,731
Jul 22	381,205	446,822	1,100,293	1,547,115	1,165,910
Aug 22	745,497	463,996	6,186,879	6,650,875	5,905,378
Sep 22	904,634	583,737	8,298,597	8,882,334	7,977,700
Oct 22	259,374	337,978	5,918,623	6,256,601	5,997,227
Total	4,518,435	4,639,882	55,145,491	59,785,373	55,266,938

[39] Futral Testimony at 13:1-20:1.

Using a 200 MW CT size cap in the PUE calculation results in a combined disallowance of $44,345,484, which is $39,827,049 higher than the PUE disallowances calculated by the Company. This quantification is detailed in the following chart. The calculations for both the 100 MW and 200 MW limitations assume that the hypothetical PUE cost per MWh is corrected for the appropriate startup costs and that the remainder of the market purchases are compared to the cost per MWh of the Company's highest cost coal-fired generating unit in the applicable month.

Kentucky Power Company
AG and KIUC Recommended PUE Disallowances
Based on 200mW Threshold
For The Twenty-Four Months November 2020 through October 2022
Case No. 2023-00008
$

Month	As Filed PUE Disallowance with $30/mWh Start-Up for All Purchases	PUE Disallowance with $4.62 mWh Start-Up for first 200 mW Purchases Each Hour	Additional PUE Disallowance for All Purchases Above 200 mW	Combined Modified PUE Disallowances	Increase in Disallowance As Filed PUE Disallowance vs Combined Modified PUE Disallowance
Nov 20	18,169	44,619	2,914	47,533	29,364
Dec 20	5,193	101,017	82,327	183,344	178,151
Jan 21	-	-	-	-	-
Feb 21	6,171	17,817	52,933	70,750	64,579
Mar 21	36,239	20,688	15,551	36,239	-
Apr 21	2,924	86,756	15,587	102,343	99,419
May 21	27,541	54,212	2,214	56,426	28,885
Jun 21	-	18,104	28,115	46,219	46,219
Jul 21	1,355	17,603	-	17,603	16,248
Aug 21	322,570	230,852	17,116	247,968	(74,602)
Sep 21	32,806	79,725	64,671	144,396	111,590
Oct 21	29,766	408,845	2,678,627	3,087,472	3,057,706
Nov 21	443,748	787,633	7,720,946	8,508,579	8,064,831
Dec 21	79,578	294,661	567,540	862,201	782,623
Jan 22	665,115	1,082,570	357,263	1,439,833	774,718
Feb 22	51,226	104,660	2,225,680	2,330,340	2,279,114
Mar 22	-	117,553	3,246,264	3,363,817	3,363,817
Apr 22	45,216	157,288	1,071,577	1,228,865	1,183,649
May 22	254,887	591,753	1,610,697	2,202,450	1,947,563
Jun 22	205,221	495,264	1,914,485	2,409,749	2,204,528
Jul 22	381,205	650,167	311,002	961,169	579,964
Aug 22	745,497	860,390	3,810,968	4,671,358	3,925,861
Sep 22	904,634	1,167,474	5,723,235	6,890,709	5,986,075
Oct 22	259,374	675,957	4,760,164	5,436,121	5,176,747
Total	4,518,435	8,065,608	36,279,876	44,345,484	39,827,049

II. The Commission Has Authority To Order Refunds of Unreasonable or Improper FAC Charges.

Contrary to Kentucky Power's claims of retroactive ratemaking, disallowing unreasonable or improper FAC expenses is consistent with the plain language of 807 KAR 5:056 and long-standing Commission precedent. The Commission has expressly held that *"all FACs are retroactive in nature"* and that *"[a]ll charges collected under a FAC are subject to review and possible disallowance."*[40] 807 KAR 5:056 explicitly requires refunds in the event that the Commission finds an electric utility has improperly calculated or applied its FAC, providing that *"fuel charges that are unreasonable* ***shall*** *be disallowed and may result in the suspension of the fuel adjustment clause based on the severity of the utility's unreasonable fuel charges and any history of unreasonable fuel charges."*[41] In six-month review cases, the Commission is required to *"order a utility to charge off and amortize, by means of a temporary decrease in rates, any adjustments the commission finds unjustified due to improper calculation or application of the charge or improper fuel procurement practices."* Because FAC charges are put into effect without prior Commission review, refund authority is inherently necessary to ensure that rates are just and reasonable.

Kentucky Power experienced such a disallowance as recently as 2015, when the Commission required the Company to refund approximately $54 million in FAC costs resulting from Kentucky Power's unreasonable allocation of *"no load"* fuel costs between native load customers and off-system sales.[42] As it does here, Kentucky Power claimed that the practice at issue was long-standing and that any change to its methodology could only be made prospectively when base rates were modified.[43] The Commission rejected those arguments, citing Kentucky Power's failure to disclose the impacts of its *"no load cost"* allocation

[40] Order, Case Nos. 94-461-A *et al.* (August 30, 1999).
[41] Emphasis added.
[42] Order, Case No. 2014-00225 (January 22, 2015).
[43] Id.

methodology in the Mitchell transfer case (2012-00578) as well as the unreasonable result produced by Kentucky Power's methodology.[44]

The Commission has issued FAC refunds in several other cases as well, including $6.7 million in charges stemming from improper line loss assumptions by Kentucky Utilities Company,[45] $8.54 million in purchased power costs collected by East Kentucky Power Cooperative,[46] $766,500 (plus interest) in improper charges by Louisville Gas & Electric, and $10.8 million in fuel contract costs recovered by Big Rivers Electric Corporation.[47]

With respect to large disallowances, the Commission has historically spread out the refunds to customers over time to lessen the immediate financial impacts to an electric utility. For example, in the *"no load"* costs decision, the Commission required Kentucky Power to refund the unlawful FAC costs over several months, consistent with length of period that those charges were collected.[48] In the Kentucky Utilities Company line losses case, the Commission amortized the refund over a 12-month period.

III. Requiring Kentucky Power To Apply The PUE Methodology In A Reasonable Manner Incentivizes The Company To Rely Upon Its Own Generation To Serve Its Customers.

807 KAR 5:056 was promulgated pursuant to both KRS 278.030(1), requiring just and reasonable rates, and KRS 278.030(2), requiring utilities to furnish *"adequate, efficient and reasonable service."* Allowing Kentucky Power to use an inflated PUE cap runs counter to both foundational statutes.

An inflated PUE cap incentivizes Kentucky Power to rely on PJM market purchases to serve its native load rather than using its own generating units. With an inflated PUE, the

[44] Order, Case No. 2014-00225 (January 22, 2015) at 10-11.
[45] Order, Case Nos. 94-461-A *et al.* (August 30, 1999).
[46] Order, Case No. 2014-00226 (July 10, 2015).
[47] Order, Case No. 90-360C-C (July 21, 1994).
[48] Order, Case No. 2014-00225 (January 22, 2015) at 13.

Company will be more likely to not operate its baseload generating units or to operate them at a lower capacity factor.[49] This lack of incentive was observable over the two-year review period. During that period, Kentucky Power had total generating capacity of 1,430 MW - 50% of Mitchell Unit 1 (780 MW of coal-fired generation), 50% of Mitchell Unit 2 (780 MW of coal-fired generation), 100% of Big Sandy 1 (260 MW of natural gas-fired generation), and a contractual entitlement in 15% of the 1,300 MW Rockport Unit 1 and 15% of the 1,300 MW Rockport Unit 2 through December 2022.[50] Thus, Kentucky Power had more than enough nameplate capacity to serve its average native load of 654 MW.[51]

However, the Company's low fuel cost baseload coal-fired generating units performed poorly, operating at low capacity factors or not operating at all in most months during the review period.[52] For example, Rockport 1 didn't operate at all for eight months, Rockport 2 didn't operate at all for eight months, Mitchell 1 didn't operate at all for seven months, and Mitchell 2 didn't operate at all for four months.[53]

The performance of Kentucky Power's generating units in October 2022 was especially poor. In fact, not one of the Company's generating units was available to run during any hour in that month.[54] In October 2022, the Company purchased 100% of its native load energy requirements at an average cost of $57.94/MWh, substantially more than the average cost of its coal-fired generating units had they operated. The performance of the Company's generating units in March 2022 also was very poor, with zero or near zero capacity factors among all of the Company's coal units.[55]

[49] Futral Testimony at 11:2-9.
[50] Kollen Testimony at 7:21-8:4.
[51] Id. at 8:5-7.
[52] Id. at 8:11-13.
[53] Id. at 8:11-16.
[54] Id. at 11:1-2.
[55] Kollen Testimony at 11:7-8.

Because of the poor performance of its power plants, during the review period the Company made energy purchases of $238.7 million.[56] Because of an inflated PUE cap, the Company claims that 98.1% of these purchases were economy.[57]

Customers paid approximately $173 million annually ($346 million over the two-year review period) for the investment costs and non-fuel operating expenses of Kentucky Power's generating units during the review period through base rates, the environmental surcharge, and Tariff PPA rates regardless of whether the generating units operated at low capacity factors or failed to operate at all.[58] They paid these high fixed costs in order to receive the benefits of lower fuel costs and lower risk, compared to the higher cost and higher risk from excessive reliance on market purchases.[59] But customers failed to receive the full benefit of the generation that they paid for.[60]

Indeed, despite having more than twice the generating capacity of its average customer load requirements during the review period, the Company purchased 44% of its energy requirements.[61] The Company purchased 5,003,180 MWh at a cost of $238.7 million, and an average cost of $47.71/MWh.[62] These purchase power costs are significantly greater than the cost of fuel at Kentucky Power's generating units, as shown below.[63]

[56] Id. at 4:13.
[57] Id.
[58] Id. at 15:19-22.
[59] Id. at 16:1-3.
[60] Kollen Testimony at 10:2-11:1.
[61] Id. at 11:14-16.
[62] Id. at 4:5-9.
[63] Id. at 4:10-12, 9, and 13-14.

Kentucky Power Generation Resources
During Two-Year FAC Review Period

Mitchell Unit 1 (coal)	390 MW Fuel Cost: $23/MWh Capacity Factor: 27.66%
Mitchell Unit 2 (coal)	390 MW Fuel Cost: $23/MWh Capacity Factor: 34.64%
Rockport Unit 1 (coal)	195 MW Fuel Cost: $37/MWh Capacity Factor: 18.99%
Rockport Unit 2 (coal)	195 MW Fuel Cost: $34/MWh Capacity Factor: 23.35%
Total Coal	1,170 MW
Big Sandy (natural gas)	260 MW $53/MWh Capacity Factor: 23.63%

In addition, if the Company's baseload coal generation operates poorly, then the Company has less low-cost energy to sell off-system.[64] The margins from off-system sales are credited to customers.[65] Therefore, the harm to customers from the poor performance of Kentucky Power's generating units is even greater than simply the effects on purchased power expense in the FAC.

IV. Kentucky Power's Proposed PJM Exemption From The FAC Regulation Should Be Rejected.

Kentucky Power argues that the PUE methodology *"does not make sense"* for the Company because it is a member of PJM. The Company advocates for an approach under which all of its PJM energy purchases would automatically be recoverable through the FAC.[66] This recommendation is contrary to both 807 KAR 5:056 and Commission precedent.

Under Kentucky Power's approach, the *"economy"* and *"non-economy"* distinction within 807 KAR 5:056 and Commission precedent would be erased and any energy purchases from

[64] Kollen Testimony at 15:11-12.
[65] Id. at 15:12-13.
[66] Vaughan Rebuttal Testimony at 12:3-12.

PJM, no matter how expensive, would be considered recoverable through the FAC. This would further reduce the incentive for Kentucky Power to rely upon its owned generating units to serve native load.

The Commission recently held that *"[u]tilities are not entitled to carte blanche recovery of fuel and purchased power costs. The FAC of course has limitations. Further, mere incurrence of fuel or purchased power costs does not make the costs prudent, reasonable or recoverable. For instance…the Commission has previously noted that limitations of the FAC regarding 'non-economy energy purchases' were important 'in order to incentivize utilities to keep outages to a minimum and to have sufficient capacity to meet load.'"*[67]

The Commission has likewise repeatedly expressed its expectation that *"utilities will invest in their service territories"* and have *"steel in the ground."*[68] The Commission has explained that *"[t]o expect otherwise would open the door to runaway costs and turning over our reliability fate to out-of-state and unaccountable entities."*[69] And the Commission has made clear that it *"has no interest in allowing Kentucky's regulated, vertically integrated utilities to effectively depend on the market for generation or capacity for any sustained period of time."*[70] Kentucky Power's requested approach is at cross-purposes with the Commission's positions.

Adopting Kentucky Power's proposed approach will hinder Kentucky's move toward increased scrutiny of FAC costs. In 2022, the Kentucky Senate passed a resolution (SR 316) urging the Commission to examine strategies to address utility costs to customers, including examining utility fuel cost recovery.[71] Responding to SR 316, the Commission opened a general investigation to investigate FACs and other recovery alternatives. In doing so, the Commission

[67] Order, Case No. 2023-00145 (June 23, 2023) at 12.
[68] Order, Case No. 2023-00102 (January 25, 2024); Order, Case No. 2022-00402 (November 6, 2023); Order, Case No. 2023-00153 (October 31, 2023).
[69] Order, Case No. 2022-00402 (November 6, 2023).
[70] Order, Case No. 2023-00153 (October 31, 2023).
[71] Order, Case No. 2022-00190 at 1.

posited that *"[i]f a generator can recover [fuel] costs across different areas such as base rates and riders regardless of their reasonable actions, these recovery mechanisms could create a perverse incentive for a utility to not pursue prudence activities. A generator may postpone maintenance (and its related expense) on a generating unit if recovery of the cost of replacement power is guaranteed."*[72] The Commission also discussed the potential need for greater review of the reasonableness of both FAC and non-FAC expenses sought for recovery in base rates.[73] But Kentucky Power's approach will allow more costs to be flowed through the FAC with less review.

Nor has Kentucky Power demonstrated that it would act prudently if given the PJM *"carte blanche*" it requests. In conducting a similar two-year review of fuel and purchased power costs, the Public Service Commission of West Virginia ("WV Commission") recently found that AEP's affiliate, Appalachian Power, failed to minimize PJM market purchases and failed to maximize its self-generation. Due to Appalachian Power's inadequate coal stockpile management, it put adders on its PJM bids to reduce the likelihood of its owned generating units being dispatched.[74] Appalachian Power had its lowest level of self-generation in the past twenty years.[75] The WV Commission found that *"[i]n lieu of self-generation, the Companies' purchases of excess amounts of power from the PJM market at prices that were at the highest level in PJM History was unreasonable and the result of imprudent decisions regarding coal inventories, coal procurement, bidding into the PJM market, and minimization of out-of-service time."*[76] The WV Commission ultimately disallowed $231.8 million in costs. [77]

[72] Id. at 9.
[73] Order, Case No. 2022-00190 at 9-10.
[74] Staff Ex. 1 (Order, Case Nos. 23-0377-E-ENEC (January 9, 2024)) at 24-25.
[75] Id. at 33.
[76] Staff Ex. 1 at 36.
[77] Staff Ex. 1.

The circumstances at issue in the West Virginia proceeding share many similarities to the current case, including the use of PJM bidding adders (as high as $121.50/MWh) to reduce the chances of Kentucky Power's units being dispatched.[78] Thus, it is entirely possible that if given the *"carte blanche"* it requests, Kentucky Power would continue its overreliance on PJM market purchases rather than relying upon its own generation to satisfy its native load obligations.

It is important to require the Company to apply a reasonable PUE methodology over both the review period and on a prospective basis. By doing so, the Commission will protect customers from unjust and unreasonable charges already collected and those that may otherwise be collected going forward.

CONCLUSION

Kentucky Power misapplied the PUE methodology during the two-year review period by incorporating unrealistic startup cost and CT sizing assumptions into its calculation, resulting in unreasonable FAC charges for retail customers. The Commission should require Kentucky Power to apply reasonable assumptions to its PUE calculation and to refund between $10.24 million and $55.27 million in accordance with 807 KAR 5:056.

Respectfully submitted,
RUSSELL COLEMAN
ATTORNEY GENERAL

/s/ J. Michael West

J. MICHAEL WEST
LAWRENCE W. COOK
ANGELA M. GOAD
JOHN G. HORNE II
ASSISTANT ATTORNEYS GENERAL
1024 CAPITAL CENTER DRIVE, SUITE 200
FRANKFORT, KY 40601-8204
PH: (502) 696-5433 FAX: (502) 564-2698
MICHAEL.WEST@KY.GOV
LARRY.COOK@KY.GOV
ANGELA.GOAD@KY.GOV
JOHN.HORNE@KY.GOV

[78] Response to Staff 2-2 Part C Attachment 1.

/s/ Michael L. Kurtz
MICHAEL L. KURTZ, ESQ.
JODY KYLER COHN, ESQ.
BOEHM, KURTZ & LOWRY
36 EAST SEVENTH STREET, SUITE 1510
CINCINNATI, OHIO 45202
PH: 513.421.2255 FAX: 513.421.2764
MKURTZ@BKLLAWFIRM.COM
JKYLERCOHN@BKLLAWFIRM.COM

COUNSEL FOR KENTUCKY INDUSTRIAL UTILITY CUSTOMERS, INC.

May 15, 2024